U. S. NUCLEAR REGULATCRY COMMISSION

REGION III

Report No. 50-440/92003(DRP)

Docket No. 50-440 License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant

Inspection At: Perry Site, Perry, Ohio

Inspection Conducted: February 27 through April 13, 1992

Inspectors: A. Vegel
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Approved By: [signature] 4/27/92
R. D. Lanksbury, Chief Date
Reactor Projects
Section 3B

Inspection Summary

Inspection on February 27 through April 13, 1992 (Report No. 50-440/92003(DRP))
Areas Inspected: Routine unannounced safety inspection by resident inspectors of previously identified items; licensee event report followup; surveillance observations; maintenance observations; licensed operator requalification program; operational safety verification; event followup; licensee self assessment capability; and shutdown risk evaluation review.

Results: Of the nine areas inspected, five non-cited violations (NCVs) were identified, four in the area of licensee event report followup (Paragraphs 3.c, 3.g, 3.h, and 3.1), and one due to loss of the control room ventilation envelope (Paragraph 8.b.(2)). Those five NCVs met the test of Section V.G of the Enforcement Policy. Also, one Inspection Follow-up Item was identified involving the interchanging of compression fitting components with those of another manufacturer (Paragraph 7.g).

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The following is a summary of the licensee's performance during this inspection period:

Plant Operations

Operator control of the plant at full power, during the shutdown, and subsequently in the outage was good.

Maintenance/Surveillance

The quality of observed maintenance and surveillance activities was good.

Engineering and Technical Support

Good involvement of system engineers in the identification of and disposition of deficiencies identified during the outage was noted.

Safety Assessment and Quality Verification

The quality of reviewed event reports was acceptable. Onsite and offsite review committees were evaluated as effective.

Emergency Planning

Based on the inspectors observations of the licensee's response to the March 15, 1992, Unusual Event, this area was evaluated as good.

DETAILS

1. Perscns Contacted

   a. Cleveland Electric Illuminating Company

      M. Lyster, Vice President - Nuclear
      *R. Stratman, General Manager, Perry Nuclear Power Plant (PNPP)
      *K. Donovan, Manager, Licensing and Compliance
      *M. Gmyrek, Operations Manager, PNPP
      S. Kensicki, Director, Perry Nuclear Engineering Department (PNED)
      F. Stead, Director, Perry Nuclear Support Department (PNSD)
      *H. Hegrat, Compliance Engineer, PNSD
      E. Riley, Director, Perry Nuclear Assurance Department (PNAD)
      *V. Concel, Manager, Technical Section, PNED
      *D. Conran, Compliance Engineer, PNSD
      *W. Coleman, Manager, Quality Assurance Section
      P. Volza, Manager, Radiation Protection Section
      D. Cobb, Superintendent, Plant Operations, PNPP
      K. Peck, Outage Planning
      *W. Wright, Manager, Instrumentation and Control

   b. U. S. Nuclear Regulatory Commission

      *R. Lanksbury, Chief, DRP 3B, RIII
      M. Bielby, Licensed Operator Examiner, RIII
      S. Stasek, Senior Resident Inspector, RIII
      J. Hopkins, Project Engineer
      *P. Hiland, Senior Resident Inspector, RIII
      *A. Vegel, Resident Inspector, RIII
      M. Khanna, Intern, RIII

   *Denotes those attending the exit meeting held on April 13, 1992.

2. Licensee Action on Previous Inspection Findings (92701)

   (Closed) Open Item (440/88013-01(DRS)): Implementation of 10 CFR 50.62, ATWS Rule. As documented in Inspection Report 50-440/88013, dated September 27, 1988, an inspection was previously performed to evaluate the licensee's compliance with the subject rule for anticipated transient without scram (ATWS). At the conclusion of that inspection, the licensee's design for ATWS mitigation had not been endorsed by a Office of Nuclear Reactor Regulation (NRR) safety evaluation report (SER). Pending the inspectors review of that SER this item remained open.

   By letter dated March 15, 1989, the NRR SER of the licensee's compliance with the ATWS rule was disseminated. That safety evaluation concluded that the alternate rod injection design, automatic recirculating pump trip design, and standby liquid control system (SLCS) design were in compliance with 10 CFR 50.62. However, at the time the NRR SER was completed, the licensee had not conducted a two pump performance test of the SLCS.

Licensee letter PY-CEI/NRR-0993L, dated May 11, 1989, confirmed the SLCS two pump test was completed and the results met the acceptance criteria. As stated in that letter, net injection flow exceeded 85 gpm (gallons per minute) at a pump discharge pressure exceeding 1220 psig (pounds per square inch gauge). The inspectors noted that the licensee identified "weeping" from the associated SLCS relief valves at a rate less than 0.25 gpm. Licensee memorandum from F.Von Ahn to V. Concel, dated April 3, 1989, described in detail the relief valve "weepage" and plans for further investigation to minimize that anomaly. However, the minor weepage was not considered to impact the SLCS two pump performance test.

Based on the inspectors review of the licensee's response to the requested information contained in the NRR SER of the Perry plant compliance to the ATWS rule, this item is closed.

No violations or deviations were identified

3. Licensee Event Report Followup (90712, 92700)

Through review of records, the following event reports were reviewed to determine if reportability requirements were fulfilled, immediate corrective actions were accomplished in accordance with Technical Specifications and corrective action to prevent recurrence had been established:

a. Reactor Water Cleanup System Isolation Licensee Event Reports

The inspectors reviewed eight licensee event reports (LERs) documenting reactor water cleanup (RWCU) system isolations. The following LERs were reviewed:

LER 50-440/88039-00
LER 50-440/89025-00
LER 50-440/89031-00
LER 50-440/90008-00
LER 50-440/90022-00
LER 50-440/91006-00
LER 50-440/91011-01
LER 50-440/92003-00

The inspectors reviewed the licensee's root cause evaluations and corrective actions for the above listed events. Of particular interest were the RWCU leak detection high differential flow (delta-flow) isolations documented in LERs 88039, 89025, 89031, 90022, 91011, and 92003.

The RWCU delta-flow isolation trip was one of the diverse methods included in the RWCU leak detection circuit to identify and isolate a leak from the RWCU system. The basic principle of operation of the delta-flow isolation circuitry was based on comparison of flow into and out of the RWCU system. A flow summer circuit compared inlet (suction) RWCU flow against the sum of RWCU return flow to the reactor and RWCU system blowdown flow going either to the main condenser or to the radwaste system. If the output of the flow summer exceeded the trip setpoint, indicating there was more flow going into the RWCU system than accounted for in the return and blowdown lines, a timer (set at 45 seconds) and an alarm actuated. If the trip setpoint was exceeded for longer than the 45 second timer, RWCU isolation valves closed.

Since the Perry Nuclear Power Plant received its Operating License in March of 1986, there have been numerous spurious isolations of the RWCU system caused by the delta-flow measurement. These isolations have been documented in licensee event reports with four LERs in 1986 (LERs 86039, 86056, 86068, and 86085) that discussed 17 different isolations, four LERs in 1987 (87001, 87013, 87026, 87074) that addressed 12 isolations, three LERs in 1988 (88002, 88013, 88039), which documented 3 isolations, two LERs in 1989 (89025, 89031) that discussed 4 isolations, and two in 1990 and 1991 (LERs 90022 and 91011) that discussed 3 isolations.

Despite the reduction in the number of isolations through numerous design modifications and procedure changes, complete elimination of spurious events had not been achieved and corrective actions were still in progress. The licensee's current efforts have culminated in the submission of a Technical Specification Change Request, "Reactor Water Cleanup System Isolation Actuation Instrumentation," dated October 30, 1991. The request included changes to the isolation signal setpoints for temperature and differential temperature instruments and changes to the differential flow timer setpoint. At the time of this report, the Technical Specification Change Request was under NRC review.

The inspectors also reviewed the licensee's corrective actions for the events documented in LERs 90008 and 91006. Those LERs documented RWCU isolations due to high differential temperature and procedural deficiencies.

Based on the above reviews, the inspectors concluded that the licensee evaluation of the events appeared thorough and comprehensive with corrective actions committed to in the LERs either completed or in progress. The inspectors consider the following LERs closed: 50-440/88039, 89025, 89031, 90008, 90022, 91006, 91011, and 92003.

5. (Closed) LER 50-440/89019-00: Alternate rod insertion and reactor protection system initiation signals. On June 13, 1989, while in Operational Condition 5, REFUELING, an unexpected alternate rod insertion (ARI) signal was generated. Since all control rods were inserted, no actual control rod movement occurred. However, the resulting high water level in the scram discharge volume generated an actuation of the reactor protection system (RPS).

Licensee's Investigation of Root Cause and Corrective Actions

Root Cause

As discussed in the subject LER and licensee Condition Report 89-249, the cause for this event was attributed to an inadequate design of the redundant reactivity control system (RRCS). That design inadequacy masked existing trip signals during performance of surveillance testing. As detailed in the subject LER, a trip signal was inserted during performance of Surveillance Instruction (SVI)-B21-T0212B, "ATWS-RPT Reactor Vessel Pressure High Channel Functional." At the time of that test performance, unknown to test performers, an existing trip signal was already present.

Corrective Action

To prevent recurrence, surveillance instructions that initiated ARI trip signals were revised to require channel reset prior to and after completion of the test instructions. In addition, system design changes were evaluated to provide independent indication of existing trip signals.

Inspectors Review

The inspectors reviewed sixteen surveillance test instructions (SVIs) that were revised to require reset of test signals prior to test performance. Based on the effectiveness of the procedural changes, the licensee elected not to implement a proposed engineering design change to provide independent annunciation of associated trip logic circuits. The justification for not implementing the proposed design change was documented in Design Change Package 890179, cancelled August 6, 1990. The inspectors noted that all corrective actions had been completed and an adequate engineering review was performed. This item is closed.

c. (Closed) LER 50-440/89020-00: Two Class 1 welds within the jet pump instrument nozzle configuration did not receive examination required by American Society of Mechanical Engineers (ASME), Section XI. On June 16, 1989, the licensee identified that the preservice examinations required by Technical Specifications 3.4.8 and 4.0.5 were not performed.

Licensee's Investigation of Cause and Corrective Actions

Root Cause:

The licensee identified the cause of this event to be a program deficiency. The subject welds were overlooked during the identification of welds in preparation of the Preservice Inspection Program.

Corrective Action

On June 23, 1989, the required visual and ultrasonic examinations were completed with no reportable indications. A review of construction documents was performed by the licensee's technical staff which confirmed no additional welds were overlooked during development of the Preservice Inspection Program. In addition, the licensee's Quality Assurance Department conducted a surveillance (Surveillance No. 89-304) of the Technical Department review process which confirmed the adequacy of that process.

Inspectors Review

The corrective actions taken by the licensee, as described above, appeared reasonable and adequate to prevent recurrence. Failure of the licensee to perform a preservice examination on two Class 1 welds prior to the first operating cycle was a violation of Technical Specification 3.4.8. This violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section V.G of the Enforcement Policy. This item is closed.

d. (Closed) LER 50-440/89032-00: Division 3 battery low electrolyte temperature results in high pressure core spray system inoperability. On December 22, 1989, and again on January 5, 1990, low electrolyte temperatures in the operating Division 3 battery occurred due to ventilation system equipment failures.

Licensee's Evaluation of Cause and Corrective Action

Root Cause:

The cause of the December 22 event was a blown power fuse in the associated battery room ventilation duct heater circuit. The January 5 event was due to a temperature control valve failure which allowed too much cooling water flow in the battery room ventilation cooler.

Corrective Action

In both cases the immediate corrective action was to restore proper temperature levels in the battery rooms. The heater fuse was replaced and the temperature control valve was repaired. In order to prevent recurrence, a design change was implemented to provide a low battery room temperature alarm at 73 F ($\pm$ 2.5).

Inspectors Review

The inspectors reviewed completed work orders for the corrective actions taken by the licensee. Based on completion of those corrective actions and no similar occurrences, the inspectors concluded the licensee's corrective actions were effective at preventing recurrence of this event. This item is closed.

e. (Closed) LER 50-440/90014-00: On June 21, 1990, both trains of the control room heating, ventilation and air conditioning (CRHVAC) system actuated unexpectedly in the emergency recirculation mode of operation.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined that the root causes of this event were multiple personnel errors by instrumentation and control (I&C) and contro' room personnel during corrective maintenance activities to repla a relay in the system control circuitry. Activities were inadequately reviewed prior to the start of repair. In addition, inadequate communications and insufficient review of system electrical drawings contributed to a decision not to realign the system to prevent an automatic actuation of the emergency recirculation mode.

Corrective Actions:

In order to prevent recurrence, I&C section management issued a directive to all I&C personnel discussing actions to eliminate personnel error. In addition, this event was discussed in I&C continuing training sessions. Licensed operator training programs for reading system drawings were revised to stress the importance of using the appropriate drawing for each application. Additionally, as part of the established requalification training program, this event was discussed with all plant licensed operators. All personnel concerned with this event were directly involved in the investigation, and were counseled by licensee supervision.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed. Concerning the adequacy of the corrective actions to prevent future personnel errors, licensee efforts to decrease the number of eve caused by personnel error were still in progress. The long term effectiveness of the licensee's efforts to reduce personnel errors will be evaluated during continuing assessment of licensee performance. This item is closed.

f. (Closed) LER 50-440/90023-00: On September 7, 1990, while performing a surveillance test, an operator inadvertently deenergized the reactor protection system (RPS) Bus A, resulting in nuclear steam supply shutoff system, balance of plant, residual heat removal A shutdown cooling, and reactor water cleanup isolations. The operators responded in accordance with plant procedures to restore the affected systems.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined the causes of this event were personnel errors, inattention to details, and failure to follow procedures. The operator and I&C technician performing the surveillance instruction (SVI) failed to identify the correct electrical protection assembly (EPA) which was being tested. Additionally, the operator did not recognize a problem when the circuit breaker that was to be "reset and then close" was already in the closed position. A plant administrative procedure directed the performer to notify supervision for further instruction if an instruction could not be performed as written. Supervision was not notified, and when testing proceeded the incorrect EPA was tripped and RPS Bus A was inadvertently deenergized.

Corrective Actions:

In order to prevent recurrence, the operator and I&C technician were involved in the investigation of this event. Both have been counseled on the inattention to detail when performing a SVI. To increase the awareness of personnel working on this equipment, new equipment labels were made and the applicable SVI was revised to include a descriptive title of the equipment. Additionally, this event was discussed in operator and I&C technician continuing training programs.

Inspectors Evaluation

Initial investigation of the event was documented in Inspection Report 50-440/90018, Paragraph 6.b.(6), dated October 18, 1990. During the inspection period, the inspectors reviewed applicable licensee documentation and conducted field verification of corrective action commitments. The inspectors concluded that the corrective actions were completed. While verifying that new equipment labels were installed, the inspectors identified another labeling problem. Though new labels were installed to differentiate between the 1C71-S003G and 1C71-S003C EPAs, the alternate power supply EPA's input labeling was noted to be incorrect. Specifically, the Division 1 and 2 alternate power supply EPA's input light labels indicated that the "power in" was from the motor generator set. As designed, the alternate power was received from a transformer via a voltage regulator, not the motor generator set. The licensee was evaluating what action should be taken to correct that discrepancy.

In general, for events that were caused by personnel errors, the licensee's efforts to minimize those events was still in progress. The effectiveness of the licensee effort will be evaluated during the inspectors continuing assessment of licensee performance. This item is closed.

g. (Closed) LER 50-440/90024-00: On September 9, 1990, surveillance testing resulted in all suppression pool level instrumentation being removed from service without the required Technical Specification compensatory actions being taken.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined the causes of this event were procedural deficiency, inadequate communications, and inattention to detail. Surveillance Instruction "Containment Atmosphere Monitoring Isolation Valves Seat Leakage and Position Indication Test" was deficient in that it did not control the sequence of work and did not require an approval signature at the start of the each subsection. Miscommunications occurred during shift changes and between local leak rate testing (LLRT), I&C, and operations personnel on the same shift. Inattention to detail was evident in that compensatory actions required by Technical Specifications were not recognized in the resulting plant configuration.

Corrective Actions:

Licensee actions taken to prevent recurrence included revising the applicable SVI to prohibit simultaneous performance of the subsections and requiring a unit supervisor's signature in order to begin each subsection. This event was added to the LLRT training program as an example of inadequate communication during testing. All licensed operators were trained to the lessons learned in this event during requalification training.

Inspectors Evaluation

The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed. The inspectors concluded that the licensee's corrective actions appeared reasonable and adequate to prevent recurrence. The licensee's failure to take compensatory actions as required by Technical Specification 4.5.3.2 after isolation of all suppression pool level instrumentation was a violation. The licensee identified violation is not being cited because the criteria specified in section V.G of the Enforcement Policy were satisfied. This item is closed.

h. (Closed) LER 50-440/90028-00: On October 9, 1990, during core alterations, seven containment isolation valves were inoperable for greater than 4 hours without all associated penetrations isolated in accordance with Technical Specification 3.6.4. The seven containment isolation valves had become inoperable due to the failure to perform surveillance testing required by Technical Specifications.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined the cause of this event was personnel error, inattention to detail. When reviewing the surveillance schedule on October 8, 1990, the unit supervisor failed to refer to Technical Specifications or approved instructions to determine the need to perform SVI E12-T2002, "RHR B Pump and Valve Operability Test." The unit supervisor was misled when the weekly surveillance schedule did not include "during core alterations" as one of the required modes for completion of the surveillance. As a result, the surveillance was not considered to be necessary during the plant conditions present.

Corrective Actions:

The licensee's immediate corrective action was to isolate the affected penetrations. To prevent recurrence, licensee management issued directives to all licensed control room personnel to consult approved surveillance instructions when evaluating Technical Specification applicability conditions. Plant Administrative Procedure (PAP)-1105, "Surveillance Test Control," was modified to procedurally require the same level of evaluation. Also, the weekly surveillance schedule was modified to correctly reflect the operational conditions requiring performance of SVI E12-T2002 and similar surveillances.

Inspectors Evaluation:

The inspectors reviewed the applicable licensee documentation and noted that all corrective action commitments were completed. The inspectors concluded that the licensee's corrective actions appeared reasonably adequate to prevent recurrence. The licensee's performance of core alterations without all required containment penetrations isolated was a violation of Technical Specification 3.6.4. The licensee identified violation is not being cited because the criteria specified in section V.G of the Enforcement Policy were satisfied. This item is closed.

i. (Closed) LER 50-440/90029-01: On October 10, 1990, two electrical protection assemblies (EPAs) tripped unexpectedly causing the loss of reactor protection system (RPS) Bus "B" which resulted in a nuclear steam supply shutoff system, balance of plant isolation, and residual heat removal "A" shutdown cooling system isolation. Additionally, the drywell equipment drain line inboard isolation valve did not automatically isolate.

Licensee's Evaluation of Cause and Corrective Actions

Root Cause:

The licensee concluded the cause of the unexpected loss of RPS Bus B was indeterminate. Both EPAs were tested and found to be operating properly with no adjustment required. The failure of the drywell equipment drain line inboard isolation valve to isolate was caused by a defective relay (Agastat Model EGPI-002) in the valve's control circuitry that had malfunctioned due to age related degradation.

Corrective Actions:

To prevent recurrence, the spike suppressor was replaced in the motor generator set control circuitry to eliminate potential sources of noise that might cause unnecessary EPA trips. To prevent recurrence of the drywell equipment drain line inboard isolation valve not automatically isolating, the defective relay was replaced and a program for replacement of similar relays was initiated. Functions performed by those relays not replaced in the second refueling outage were monitored by control room operators using an approved temporary instruction.

Inspectors Evaluation

The inspectors initial followup of this event was documented in Inspection Report 50-440/90020, dated December 14, 1990. During the inspection period, the inspectors reviewed applicable licensee documentation and noted that licensee corrective action commitments were completed. The inspectors concluded that licensee corrective actions appeared adequate and sufficiently comprehensive in scope to prevent recurrence. This item is closed.

J. (Closed) LER 50-440/91002-00: On January 1, 1991, while performing activities for turbine stop valve (TSV) and RPS testing, an inadvertent TSV closure signal resulted in a full scram signal being generated. At the time of the event the plant was in Operational Condition 2, STARTUP, with all of the control rods inserted.

Licensee's Evaluation of Cause and Corrective Actions

Root Cause:

The licensee concluded the root cause of this event was indeterminate. A possible electrical malfunction was investigated by troubleshooting the speed control logic. Troubleshooting efforts did not identify any equipment problems. Two surveillances in progress at the time of the event, were reviewed for possible interaction effects. Although SVI N31-T1151, "Main Turbine Valve Exercise Test," could have provided more detail for adjusting control valve position, the operator's chosen methods would not have initiated the RPS actuation and interaction between the surveillances was not found. Control room and I&C personnel were interviewed and the exact actions performed prior to the scram signal were reviewed. Although none of the individuals could distinctly remember depressing or inadvertently touching the CLOSE VALVES button, this action would have caused the TSV's to close and a scram to occur. The CLOSE VALVES control button was located in close proximity to the LOAD SET button and was observed to be lit following the scram.

Corrective Actions:

To prevent recurrence, SVI-N31-T1151 was revised to clarify the actions needed to meet all of the prerequisites. Additionally, this event was discussed during licensed operator requalification training.

Inspectors Evaluation:

The inspectors reviewed the licensee documentation and noted that all corrective action commitments were completed. In addition, the inspectors reviewed the resultant data from the licensee's investigation and troubleshooting efforts of the speed control logic with the system engineer. Based on the above reviews, the inspectors concluded that the licensee's efforts appeared adequate in attempting to determine the root cause and prevent recurrence. This item is closed.

k. (Closed) LER 50-440/91004-00: On January 20, 1991, while performing a periodic test on the reactor feedpump turbine stop valves, a fuse was blown resulting in a loss of valve position indication. Further investigation revealed that the blown fuse also supplied power to the reactor water level-high (Level 8) trip relays for the main turbine, the motor driven feedpump, and the A reactor feed pump turbine (RFPT). This blown fuse resulted in all three reactor water Level 8 channels being inoperable. Since this was not addressed by Technical Specification 3.3.9, entry into Technical Specification 3.0.3 was required.

Licensee Evaluation of Cause and Corrective Actions

Root Cause:

The licensee determined the root cause for this event was a design inadequacy. A single fuse protected the trip relay circuitry associated with the main turbine, the motor driven feedpump, and the A RFPT; however, it also protected additional nonsafety-related indication and control circuitry. An apparent voltage spike in this additional circuitry resulted in shorting out a control panel indicating lamp which caused the fuse to blow and resulted in the loss of the three trip relays.

Corrective Actions:

The corrective actions taken for this event included modifying the circuitry such that a single fuse protects only the circuitry associated with the trip relays, while another separate fuse protects the additional indication and control circuitry. Also, the licensee performed an evaluation of Technical Specifications to verify that this type of fusing arrangement did not exist in any other multiple channel Technical Specification related trip circuitry.

Inspectors Evaluation:

The inspectors evaluation of the event and the licensee's immediate corrective actions were documented previously in Inspection Report 50-440/91003, dated March 30, 1991. During the inspection period, the inspectors reviewed applicable licensee documentation and noted that all corrective action commitments were completed. The inspectors concluded that the licensee's corrective actions appeared reasonable and adequate to prevent recurrence. This item is closed.

l. (Closed) LER 50-440/91013-00: Missed main steam line flow instrumentation surveillance. On July 23, 1991, the licensee identified a required surveillance (31 day) on main steam line flow instrumentation had not been performed within the periodicity specified in the Technical Specifications. With the surveillance test not current, the affected instrumentation was to be placed in a "tripped" condition as required by the associated Technical Specification Action statement.

Licensee's Investigation of Cause and Corrective Action

Root Cause:

The cause for this event was multiple personnel errors. When ordering the surveillance test procedure for flow instrument "A," an initial error was made and the surveillance test procedure for the "B" instrument was obtained. The correct "A" test package cover sheet was attached to the "B" procedure and issued for implementation. Although numerous reviews and authorizations were obtained, the initial error was not discovered. Subsequently, test personnel performed testing on the "B" instrument (in accordance with the procedure in hand); however, acceptance of test results were noted on the test package cover sheet (i.e. the "A" instrument). The error was discovered during a document review prior to vaulting the test records.

Corrective Actions:

Immediate corrective action was to verify the proper surveillance test on the "A" instrument had been performed. On July 13, 1991, the required test had been performed with no corrections to the "A" instrument required. Licensee performance engineering personnel audited about 800 test packages awaiting transfer and no similar error was identified. In addition, all personnel involved in surveillance test performance were made aware of this event.

Inspectors Review

The inspectors verified completion of corrective actions through review of available records. The corrective actions taken appeared reasonable and adequate to prevent recurrence. Failure of the licensee to perform the required surveillance test on main steam line flow instrument "A" (E31-T0074A) within the required test interval and without complying with the associated Action statement was a violation of Technical Specifications. This violation is not being cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section V.G of the Enforcement Policy.

No deviations were identified; however, four non-cited violations (NCVs) were identified.

4. Monthly Surveillance Observation (61726)

For the surveillance activities listed below, the inspectors verified one or more of the following: testing was performed in accordance with procedures; test instrumentation was calibrated; limiting conditions for operation were met; removal and restoration of the affected components were properly accomplished; test results conformed with technical specifications, procedure requirements, and were reviewed by personnel other than the individual directing the test; and any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Surveillance Test No.	Activity
SVI-B33-T0257	End of Cycle Recirculation Pump Trip Breaker Arc Suppression Response Time Testing For 1B33A-CB3A and CB3B
SVI-R43-T1318	Diesel Generator Start and Load - Division 2
SVI-D51-T0304-C	Triaxial Response Spectrum Recorder Channel Calibration
SVI-L51-T2010	Functional Testing of Snubbers
TXI-0132	Dynamic Diagnostic Valve Testing
SVI-E22-T1329	Division 3 Diesel Generator 18 Month Functional Test

a. Regarding SVI-R43-T1318, the surveillance had been attempted the previous day with operators encountering a problem with an anomalous status indication for the diesel generators (DG) ground fault detector. Following shutdown of the engine, personnel determined that contacts associated with the ground fault detector (64X relay) required cleaning. This was subsequently completed and the surveillance re-performed with the inspector in attendance. However, with the DG in operation and loaded to its respective bus, operators again noted that the ground fault detector status light was not illuminated as expected. The DG was unloaded and further checks were conducted. It was determined that the 64X relay was a manual latch type and should have been manually reset before being returned to service. This apparently was not done. Subsequently, the relay was reset and the surveillance satisfactorily completed.

b. Regarding TXI-0132, the inspectors observed dynamic testing and reviewed collected data for suppression pool cleanup (SPCU) system isolation valves 1E12-F609 and 1E12-F610. The motor-operated valves were tested by the licensee in accordance with their planned test program responding to Generic Letter 89-10. Although used as a reference, the inspectors did not address each of the criteria detailed in Temporary Instruction (TI) 2515/109, "Inspection Requirements For Generic Letter 89-10." Inspection of the licensee's motor-operated valve test program in accordance with TI 2515/109 will be documented in a future inspection report.

Prior to observing the dynamic testing, the inspectors reviewed licensee Audit Report PA 91-32, "Safety-Related Motor-Operated Valve Testing and Surveillance Program," dated January 29, 1992. That report identified the current strengths in the motor-operated valve test program as well as items requiring additional attention. The inspectors noted that the results of that audit report were provided to the appropriate levels of licensee management.

The test performance was accomplished in accordance with approved test procedures located at the work site and in the control room. The inspectors noted that a test anomaly identified during testing of the 609 valve required adjustment of the associated torque switch setting. That adjustment was made in accordance with the licensee's setpoint control program. Condition Report 92-032 was initiated to document the results of the investigation into the anomaly. Testing of the 610 valve was observed by the inspectors at the work location and from the control room. The 610 valve test was performed twice since a test equipment failure (lap-top computer) did not allow retrieval of initial test data.

Following test performance, the inspectors reviewed collected data and discussed the results with cognizant licensee personnel. The inspectors concluded that, for the two valves tested, adequate controls were in place to perform testing and retrieve data for engineering evaluations.

No violations or deviations were identified.

5. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed and/or reviewed to ascertain that activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

Specific Maintenance Activities Observed:

Reactor Vessel Nozzle Flush

Drywell Scaffold Erection

Safety Relief Valve Removal

Main Steam Isolation Valve Removal

Circulating Water System Drain

Electrical Protection Assembly (EPA) Repair

Reactor Water Cleanup Pipe Chemical Cleaning

Division 1 and 3 Diesel Generator Maintenance

Emergency Service Water Disassemble/Inspection 1P45-F0552

Main Turbine Lower Pressure-A Inspection

No violations or deviations were identified.

6. <u>Perry Requalification Program Audit</u>

During the report period, a NRC Region III operator licensing examiner performed an unannounced audit of the Perry requalification program. The purpose of the audit was to evaluate the content and effectiveness of the licensee's licensed operator requalification evaluation program. Although NUREG 1021, Operator Licensing Examiner Standards, was used as a guideline during performance of the audit, the audit was not intended to imply that requirements beyond those commitments in the licensee's requalification program were required.

The examiner observed administration of the following examinations to an operations crew and a staff crew:

1) Part A (Plant and Control Systems) and Part B (Administrative Controls/Procedural Limits) written.

2) Control room, inplant, and simulator job performance measures (JPMs).

3) Dynamic simulator scenarios.

The following observations were made during the audit, and discussed with the Perry Training Manager and other members of the training staff at an exit meeting on March 6, 1992:

a. Both the format and content of the written examination for Part A (Plant and Control Systems) and Part B (Administrative Controls/Procedural Limits) were generally consistent with NUREG 1021, examination standard (ES)-602. Several of the facility questions were short answer. Additionally, the point value per question varied, based on the facility's time validation and safety significance evaluation. Consistency of grading for examinations with these types of questions was discussed with the licensee.

Overall administration of the Part A and B examinations was consistent with NUREG 1021, ES-602. Crew briefings held prior to the written examinations utilized an appropriately modified form of the ES-201, Attachment 1, Enclosure 3 briefing sheet. The examinations were continuously proctored. Grades were documented and questions evaluated for generic and individual weaknesses.

b. Both the format and content of JPMs and associated questions were consistent with NUREG 1021, ES-603. Several of the facility JPM questions were multiple choice, which was consistent with previous NRC administered requalification examinations. During the exit meeting, the licensee was referenced to ES-603-1, step 4, which stated, "JPM questions require responses of 2 to 3 sentences ..."

The licensee had recently received guidelines for developing JPMs. The guidance concerned development of JPMs which test alternate success path(s) for a specific task. The licensee was reviewing the information for incorporation into their program.

Administration of JPMs was consistent with NUREG 1021, ES-603. Selection of JPMs for each individual utilized the two on one approach, one evaluator per two operators. Crew briefings held prior to the JPMs utilized ES-603, Attachment 1. Although not covered in NUREG 1021, the evaluators accepted answers at any time prior to the completion of the JPM examination. This appeared to contradict briefing directions to inform the evaluator when the operators completed answering the question. Instructors used appropriate clarifying questions at the end of JPMs to verify operator actions. There were no observed instances of cuing by the instructor. However, on one occasion, the operator not performing a JPM located a valve in the overhead structure with his eyes for the operator performing a JPM. On a separate occasion, the operator not performing a simulator JPM began acknowledging alarms associated with the JPM being performed by another operator. It was expected that operators performing simulator JPMs would acknowledge their own alarms, and verify they were normal. During the exit meeting, inadvertent cuing was discussed with the licensee.

c. Both the format and content of dynamic simulator scenarios were consistent with NUREG 1021, ES-604. The selection of scenarios for each crew covered a relatively broad spectrum of the Perry emergency instructions (PEIs), off normal instructions (ONIs), integrated operating instructions (IOIs), system operating instructions (SOIs), and alarm response instructions (ARIs). The scenarios were written to exercise various portions of the PEI flow paths. However, the selection of individual simulator critical tasks (ISCTs) was not always consistent with NUREG 1021. For example, PEI entry conditions were listed as ISCTs. Additionally, actions to be performed by the reactor operator (RO) were appropriately listed as ISCTs, but the senior reactor operator (SRO) directions to the RO to perform these actions were not listed as ISCTs.

Administration of the dynamic simulator scenarios was consistent with NUREG 1021, ES-604. Crew briefings held prior to the scenarios utilized ES-604, Attachment 2. Coordination of the scenario events was good. Two training instructors evaluated the four person crews, and a third instructor handled crew communications and operated the simulator. All three instructors were in radio communication. There were no instances of inadvertent instructor cuing observed. Post scenario crew evaluations utilized ES-604 Attachments 2 and 4. Training staff evaluations identified significant crew and individual weaknesses in command and control, communications, and RO/SRO actions.

d. A discussion was held with the training staff concerning remediation of operators demonstrating weaknesses and unsatisfactory performance during the annual requalification examination. The licensee stated that the operations department would be immediately contacted concerning individual or crew failures. The operations department would ensure those individuals would not go back on shift. The training department would remediate individuals in the associated areas of weakness and failure. The individuals would be required to retake and successfully pass an examination on those unsatisfactory areas prior to assuming normal shift duties.

No violations or deviations were identified.

7. <u>Operational Safety Verification (71707)</u>

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during this inspection period. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified tracking of Limiting Conditions for Operation associated with affected components. Tours of the pump houses, control complex, the intermediate, auxiliary, reactor, radwaste, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for certain pieces of equipment in need of maintenance. The inspectors by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping, general plant cleanliness conditions, and verified implementation of radiation protection controls.

a. <u>Containment Integrity</u>

On February 26, 1992, the licensee reported a loss of containment integrity while operating at 100 percent power. The inspectors initial review of that event was documented in Inspection Report 50-440/92002, Paragraph 7.6.(3), dated March 13, 1992. During the report period, the licensee completed their investigation, concluded that a loss of containment integrity had not occurred, and retracted the notification on March 24, 1992.

The inspectors reviewed the licensee's basis for the conclusion that containment integrity had been maintained in accordance with Technical Specifications. Licensee Condition Report 92-031, dated February 26, 1992, documented the investigation into the subject event. In addition, licensee memorandum H. Hegrat to K. Donovan, dated March 12, 1992, was reviewed by the inspectors.

As previously documented in Inspection Report 50-440/92002, planned local leak rate testing of a containment vacuum breaker penetration was in progress on February 26. During that test performance, a planned maintenance activity was commenced on the respective vacuum breaker outboard isolation valve. During that maintenance effort, control room personnel questioned the integrity of the inboard isolation valve (vacuum breaker check valve) since test equipment was left installed. Although initially reported as a loss of containment integrity, further evaluation determined that the inboard isolation check valve was capable of performing its containment isolation function. Based on the inspectors review of work records, the inboard isolation check valve was capable of performing its containment isolation function prior to commencing work on the outboard isolation valve. Therefore, the licensee's conclusion that containment integrity was maintained throughout the work activities on February 26 was appropriate.

In addition to containment integrity, the inboard vacuum breaker isolation valve and the outboard isolation valves were required to be operable in accordance with Technical Specification 3.6.4. At the time maintenance work started on the outboard isolation, Technical Specification 3.6.4, Action "a," required that within 4 hours the affected penetration be isolated; otherwise, be in at least HOT SHUTDOWN within the next 12 hours. The inspectors noted that the licensee had not initially recognized the requirement to isolate the penetration within 4 hours; however, the penetration was isolated within the total time of 16 hours (4 + 12). The inspectors concluded that the Technical Specifications had been complied with for this event.

b. <u>Reactor Recirculation Sample Line Isolation</u>

On March 9, 1992, during performance of System Operating Instruction (SOI) C-71, "Transfer of Reactor Protection System (RPS) Bus A to Alternate Supply," automatic closure of reactor sample isolation valve B33-F020 occurred. B33-F020 is one of two isolation valves installed in series on the reactor recirculation sample line. The valves isolate the sample line between the drywell and the sample station located inside containment. In accordance with SOI C-71, the operator was instructed to manually shut this valve prior to transferring the RPS bus. The operator failed to isolate the valve and the valve then shut automatically when power was secured during the transfer.

The licensee initially reported the unexpected automatic isolation of B33-F020 during the RPS bus transfer as an actuation of an engineered safety feature (ESF) on March 9, 1992. Subsequently, on March 24, the licensee retracted the notification because the recirculation sample isolation was not an ESF actuation as described in the Updated Safety Analysis Report or a containment isolation listed in the Technical Specifications.

The inspectors reviewed the licensee's reportability determination and concluded that the licensee's assessment of the event as not reportable appeared reasonable. Concerning the cause of the event (i.e. personnel error), the inspectors will evaluate the licensee's actions to prevent recurrence during routine assessment of licensee's performance in this area.

c. <u>Plant Shutdown</u>

On March 21, 1992, the Perry Plant was shut down, commencing the third refueling outage. The inspectors observed control room activities during the shutdown to assess operator control of the evolution and compliance with plant procedures. The inspectors concluded that the shift supervisors and unit supervisors exercised positive control of the evolution which resulted in a deliberate and well coordinated shutdown. The inspectors also noted good communications and decorum in the control room. During the shutdown, no unexpected plant equipment problems were encountered except for an unplanned reactor water cleanup (RWCU) isolation. The plant operators performed the shutdown and properly responded to the RWCU isolation in accordance with plant procedures. The RWCU isolation is described in Paragraph 8.b.(5) of this report.

d. <u>Storage Trailer Fire Followup</u>

As previously documented in Inspection Report (IR) 50-440/91025, Paragraph 6.b.(3), dated January 29, 1992, the inspectors reviewed the licensee's initial response to a fire that occurred within the owner controlled area. At the completion of that inspection the cause of the fire was still under investigation by the licensee.

During the report period, the inspectors reviewed licensee Condition Report (CR) 91-239, dated December 14, 1991, which documented the investigation into the cause of the subject fire. Samples of fire debris were analyzed by the Lake County Regional Forensic Laboratory and no detectable fire accelerants were identified. As documented in CR 91-239, the root cause of the fire was undetermined.

The inspectors initial documentation (IR 50-440/91025) referred to the fire location as a "Hazardous Waste Storage Trailer." That reference was not an accurate description. The subject trailer was used for storage of chemicals needed in the repair of plant equipment. In accordance with the licensee's administrative procedures, chemical permits had been issued. As documented in those permits, some of the chemicals were defined as hazardous with appropriate instructions for disposal.

e. Plant Tour With Management

During the report period, the inspectors toured areas of the plant with licensee management personnel. The purpose of these tours was to convey first-hand observations made by the inspectors. A tour of the fuel building was con 'ucted with the acting maintenance manager during whic' u. inspectors discussed housekeeping and cleanliness zones in preparation for fuel movement activities. A general tour of accessible plant areas was conducted with the instrumentation and control (I&C) manager during which the inspectors discussed housekeeping, equipment material conditions, and radiological controls.

f. Circulating Water Pipe Walkdown

During the report period, the inspectors performed a walkdown of the 12 foot diameter circulating water system piping. With the system drained, the inspectors, accompanied by the licensee's system engineer, traversed the entire internal length of both the supply and return circulating water 12 foot diameter piping. The inspectors observed ongoing inspection activities and discussed planned repairs for identified anomalies. In general, the internal condition of the circulating water pipe appeared good. The licensee had identified one significant crack at the carbon steel to fiberglass joint near the pumps discharge. Corrective actions to repair the joint were in progress.

g. Compression Tube Fittings

While conducting routine tours, the inspectors noted several examples where components of compression tube fittings were interchanged with those of another manufacturer. Specifically, the tube fitting body and the associated nuts were manufactured by different vendors. These questionably configured compression fittings were identified on various instrument racks including safety-related instrument manifolds. Some of the safety systems which were affected included the residual heat removal, low pressure core spray, and the high pressure core spray systems.

As discussed in NRC Information Notice 92-15, "Failure of Primary System Compression Fitting," the interchanging of hardware from different manufacturers was one of the problems that might impact the effectiveness of the compression fit. The inspectors identified the specific fittings in question to the licensee. At the end of the inspection period the licensee was in the process of evaluating the inspectors findings. This will remain an Inspection Follow-up Item (50-440/92003-01(DRP)) pending the inspectors review of the licensees corrective action.

No violations or deviations were identified. One Inspection Follow-up Item was identified.

8. Onsite followup of Events at Operating Power Reactors (93702

a. General

The inspectors performed onsite followup activities for events which occurred during the inspection period. Followup inspection included one or more of the following: reviews of operating logs, procedures, and condition reports; direct observation of licensee actions; and interviews of licensee personnel. For each event, the inspectors reviewed one or more of the following: the sequence of actions; the functioning of safety systems required by plant conditions; licensee actions to verify consistency with plant procedures and license conditions; and verification of the nature of the event. Additionally, in some cases, the inspectors verified that licensee investigation had identified root causes of equipment malfunctions and/or personnel errors and were taking or had taken appropriate corrective actions. Details of the events and licensee corrective actions noted during the inspector's followup are provided in paragraph b. below.

b. Details

(1) Loss of Reactor Protection System Bus

On February 27, 1992, at about 9:45 p.m., while operating at 100 percent power, an unexpected loss of the reactor protection system (RPS) Bus "B" occurred. By design, a loss of RPS B resulted in an automatic inboard balance of plant (BOP) isolation and a reactor water cleanup (RWCU) system isolation. Plant operators responded to this event by transferring RPS B to its alternate power supply and resetting the BOP and RWCU isolation signals. RPS B remained on its alternate power supply until troubleshooting and repairs were completed on March 4.

The licensee informed the NRC Operations Center of this event via the emergency notification system (ENS) at about 1:00 a.m. on February 28, 1992. Subsequent investigation into the cause of this event identified a failed electric protection assembly (EPA) logic card that had been installed as a planned maintenance activity just prior to event occurrence. Specific details of this event were described in Licensee Event Report (LER) 440/92001, dated March 27, 1992.

(2) Loss of Control Room Ventilation Envelope

On February 28, 1992, at about 11:30 a.m., while operating at 100 percent power, the licensee identified that the control room ventilation envelope had been lost when a 3 inch diameter plug was removed from a spare electrical penetration. Upon identification, the licensee initiated actions to restore the control room envelope and comply with the provisions of Technical Specification 3.0.3. At about 12:00 Noon the 3 inch plug was reinstalled restoring the required control room ventilation envelope. No actual power reduction occurred.

The licensee informed the NRC Operations Center of this event via the ENS at about 1:00 p.m. on February 28. Subsequent investigation into the root cause of this event identified a program deficiency that allowed removal of the 3 inch plug for a planned modification. Existing controls required the evaluation of the removed plug as a degraded fire barrier; however, the coincident effect on the control room ventilation envelope was not required to be evaluated. Specific details of this event were described in LER 440/92002, dated March 27, 1992.

With a loss of the control room ventilation envelope, both trains of the emergency recirculation mode of the control room heating, ventilation, and air conditioning were made inoperable in violation of Technical Specification 3.7.2. This violation is not being cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section V.G of the Enforcement Policy.

(3) Reactor Water Cleanup Isolation

On February 28, 1992, at about 9:30 p.m., while operating at 100 percent power, an unexpected isolation of the reactor water cleanup system occurred. At the time of event occurrence, plant operators were returning the reactor water cleanup system to service following corrective maintenance on associated instrumentation.

During the system restoration process a high differential flow alarm initiated when the system valves were opened to allow warmup of the piping. Attempts by operators to stabilize flow prior to the 45 second automatic isolation were unsuccessful. Upon verification that the system had properly isolated and no actual system leak was present, the reactor water cleanup system was unisolated and returned to service about 12 hours after this event occurrence.

The licensee informed the NRC Operations Center of this event via the ENS at 11:30 p.m. on February 28. The licensee submitted LER 440/92003, dated March 27, 1992, for this event. The inspectors review of LER 440/92003 is documented in Paragraph 3.a. of this inspection report.

(4) Earthquake - Unusual Event

On March 15, 1992, at about 1:15 a.m., while operating at 99 percent power, an earthquake with a magnitude of approximately 3.5 Richter occurred in the vicinity of the Perry plant. The initial tremor was felt by plant operators and actuated installed seismic recorder instrumentation. With the automatic actuation of seismic recorders and ground motion being felt by plant personnel, the licensee declared an Unusual Event at about 1:45 a.m. in accordance with the plant's emergency plan.

The inspectors observed the licensee's response to this event shortly after the Unusual Event declaration until the termination of the event. The shift supervisor directed that plant walkdowns be performed in all accessible areas of the plant to identify any visible indications of the effect from the earthquake. In addition, plant personnel responsible for evaluating seismic recorders were called in to confirm that the operating basis earthquake (OBE) had not been exceeded. After completion of the plant walkdowns and confirmation that the OBE had not been exceeded, the Unusual Event was terminated at 4:45 a.m.

The licensee informed the NRC Operations Center of this event via the ENS at 1:52 a.m. on March 15.

Followup evaluation of seismic records identified two instruments that recorded motion equal to or above 0.05g. In accordance with Technical Specifications, the licensee submitted a Special Report in letter PY-CEI/NRR-1471L, dated March 25, 1992.

(5) <u>Reactor Water Cleanup Isolation</u>

On March 21, 1992, at 1:00 p.m., while in Operational Condition 2, SHUTDOWN, an unexpected isolation of the reactor water cleanup (RWCU) system occurred. At the time of event occurrence, a plant shutdown was in progress for a refueling outage. Plant operators verified that the RWCU system properly isolated, apparently due to a high differential flow. After confirmation that an actual system leak was not the reason for the high differential flow, the RWCU was returned to service. In addition, the licensee was to submit a licensee event report (LER) in accordance with 10 CFR 50.73.

The licensee informed the NRC Operations Center of this event via the ENS at about 3:45 p.m. on March 21.

(6) <u>Excessive Secondary Containment Bypass Leakage</u>

On March 26, 1992, at about 6:30 a.m., while in COLD SHUTDOWN for a refueling outage, the licensee identified excessive leakage past an instrument air supply header inboard check valve of about 3,500 standard cubic centimeters per minute (SCCM). That excess leakage, combined with known leakage, exceeded Technical Specification 3.6.1.2.d limits of 0.0504L_a (5,051.7 SCCM). The identification of excess leakage was made during planned surveillance tests conducted during the refueling outage. The licensee initiated Condition Report 92-052 to document the root cause investigation and corrective action. In addition, the licensee was to submit a LER in accordance with 10 CFR 50.73.

The licensee informed the NRC Operations Center of this event via the ENS at about 8:45 a.m. on March 26.

(7) Excessive Leakage Through Main Steam Isolation Valve (MSIV) Penetrations.

On March 28, 1992, at 2:30 p.m., while in COLD SHUTDOWN for a refueling outage, the licensee identified MSIV penetration leakage in excess of Technical Specification limits. As noted in licensee Condition Report 92-058, the "B" main steam line containment penetration failed to meet the 25 standard cubic feet per hour (SCFH) when tested in accordance with the applicable test procedure. Subsequently, the "D" MSIV penetration and the "A" MSIV penetration also failed to meet the 25 SCFH acceptance criteria. The licensee initiated corrective action to troubleshoot and make repairs to boundary isolation valves identified as leakage paths. Inspection of the licensee's leak-rate test performance for the subject MSIV penetrations was performed by a NRC Region III specialist. The results of that inspection were to be documented in Inspection Report 50-440/92004.

The licensee initially notified the NRC Operations Center of this event via the ENS at about 4:30 p.m. on March 28. Additional notifications were made by the licensee on March 28 and 29 informing the NRC Operations Center of the subsequent test failures.

(8) Reactor Scram Signal While Shutdown

On March 31, 1992, at about 4:30 a.m., while in COLD SHUTDOWN for a refueling outage, an unexpected reactor trip signal was received. At the time of event occurrence, all control rods were fully inserted; therefore, no actual control rod movement occurred. With a Division 1 electrical outage in progress, an existing half-scram signal was present at the time of event occurrence. Apparently, personnel performing work activities below the reactor vessel "bumped" instrument cable(s) resulting in a momentary spike of a local power range monitor and satisfying the coincident trip circuitry. Immediate actions by plant personnel were to stop work under the reactor vessel and perform an inspection of that area. No evidence of damage was observed. Subsequently, the scram signal was reset and work under the vessel resumed.

The licensee informed the NRC Operations Center of this event via the ENS at about 7:30 a.m. on March 31.

(9) Reactor Protection System (RPS) Trip Signal

On April 6, 1992, at about 9:30 p.m., while in Operational Condition 5, REFUELING, the licensee experienced two unexpected RPS trips. At the time of event occurrence all control rods were fully inserted; therefore, no actual control rod motion occurred. The cause for the event was a momentary spike on intermediate range monitor (IRM) "E" coincident with a planned surveillance test on main steam line radiation monitors. With a half-scram signal present from the planned surveillance test, the IRM spike satisfied the RPS trip logic. Immediately after the first trip signal, plant operators were able to reset the scram logic on Channel A/C; however, a second spike on IRM "E" occurred about one minute later resulting in a second RPS trip. The IRM spiking was believed to be due to welding activities ongoing in the drywell at the time of event occurrence.

The licensee informed the NRC Operations Center of this event via the ENS at about 11:45 p.m. on April 6. The licensee initiated Condition Report 92-080 to document the investigation and corrective action for this event.

(10) Combined Primary Containment Leak Rate Test Failure

On April 7, 1992, at about 6:30 a.m., while in a refueling outage, the licensee identified primary containment leakage rates were in excess of Technical Specification limits. During Type C leak rate testing of a main steam drain line penetration, the measured leakage was in excess of 200 standard liters per minute (SLM). That as-found leakage resulted in the combined leakage for all penetrations to exceed the Technical Specification 3.6.1.2.b limit of 0.60 L_a (percent/24 hours).

The licensee initially informed the NRC Operations Center via the ENS of this test failure on April 5. That initial notification was an informational followup to the secondary containment bypass leakage discussed above in Paragraph 8.b.(6). After further evaluation of test data, the licensee reported the subject event to the NRC Operations Center via the ENS at about 8:00 a.m. on April 7.

(11) Hydrostatic Leak Rate Test Failure

On April 8, 1992, at about 2:30 p.m., while in a refueling outage, the licensee identified that the combined leakage for hydrostatically tested lines was in excess of allowable. During Type C leak rate testing of a feedwater penetration, the measured leakage, when added to previously identified leakage, exceeded Technical Specification 3.6.1.2.e limit of 1 gpm (gallon per minute) times the total number of containment isolation valves in hydrostatically tested lines. At Perry, the total combined leakage allowable for hydrostatically tested valves was 23.0 gpm.

The licensee informed the NRC Operations Center of the event via the ENS at about 5:00 p.m. on April 8.

No deviations were identified; however, one non-cited violation (NCV) was identified.

9. Evaluation of Licensee Self-Assessment Capability (40500)

a. On-Site Review Committee

During the report period, the inspectors observed on-site review committee meetings to evaluate that organization's effectiveness. For the meeting attended, the inspectors considered the following attributes: degree of plant management involvement and/or domination of discussions; if constructive discussion occurred; if the majority of the committee consistently voted the same as the chairman; if the committee was biased toward operation or safety; and, if the committee used design basis, FSAR, or vendor technical manuals for their determinations in addition to the Technical Specifications.

In preparation for the attended meetings, the inspectors reviewed draft submittals of items that were submitted for the on-site review committee's approval. Items presented to the on-site review committee included safety evaluations, temporary changes to procedures, setpoint change requests, procedural revisions, and design change packages.

During this report period, the following on-site review committee meetings were observed by the inspectors:

Meeting No.	Date
92-024	03/19/92
92-027	03/25/92

For the meetings observed, the inspectors concluded that the function of the on-site review committee was effectively implemented.

b. Offsite Review Committee

During this inspection period the inspectors reviewed the licensee's offsite review committee activities which were performed by the nuclear safety review committee (NSRC). To determine if the functions of the committee were being performed in accordance with regulatory requirements, the inspectors reviewed licensee documentation governing the composition, duties and responsibilities of the NSRC, including section 6.5.2 of the Technical Specifications. The inspectors reviewed previous NSRC meeting minutes and attended an NSRC meeting to evaluate the effectiveness of the committee to provide an independent review and audit of plant activities.

On March 12, 1992, the inspectors attended the quarterly NSRC meeting. The members were well qualified and prepared to perform the committee reviews. The quorum, composition, and function of the NSRC was in compliance with Technical Specification requirements. The NSRC meeting included reviews of the shutdown risk assessment for the refueling outage, the control of switchyard activities during the outage and reviews of various subcommittee reports.

The inspectors concluded that the NSRC was objective and effective in the review of plant activities and that the Technical Specification requirements for the committee were being met.

No violations or deviations were identified.

10. <u>Reliable Decay Heat Removal During Outages (2515/113)</u>

A review of the licensee's planned activities for refueling outage number 3 (RF-3) was conducted using Temporary Instruction 2515/113, "Reliable Decay Heat Removal During Outages." The inspectors reviewed the RF-3 schedule to determine what actions or considerations were taken by the licensee to ensure reliable decay heat removal capability would be maintained during the outage.

The licensee developed the RF-3 schedule using Perry Administrative Procedure (PAP) 0115, Revision 2, "Outage Planning." That administrative procedure had guidelines regarding the minimum number of electrical power sources, emergency core cooling systems (ECCS), and decay heat removal systems desired during Operational Conditions 5, REFUELING.

During the development of the RF-3 schedule, the licensee evaluated outage risk management issues using the Institute of Nuclear Power Operations (INPO) "Guidance for Managing Shutdown Safety," Nuclear Management and Resources Council (NUMARC) "Guidelines for Industry Actions to Assess Shutdown Management (NUMARC 91-06)," and recent industry events. Based on that evaluation, an outage risk management philosophy memorandum was issued which detailed how the RF-3 schedule complied with the INPO guidelines. Additionally, contingency plans for providing alternate power to decay heat removal systems; to auxiliary hoists for closing the containment equipment hatch; and cross connecting Division 1 and 2 Class 1E busses in the event of a loss of offsite power were prepared.

The outage planning section requested an independent review of the RF-3 schedule. An outage risk review team was assembled to review the schedule for potential reactor vessel drain down situations based on evolutions in progress and single valve protection; the capability to close containment; and establish a level of defense for loss of offsite power and decay heat removal. The cross-functional team was composed of members from the operation's department, the independent safety engineering group, quality assurance, engineering, and licensing. Guidelines for the review were developed using PAP-0115, "INPO Guidance for Managing Shutdown Safety," NUMARC 91-06, and other industry events. Revisions to the outage schedule and to the contingency plans were made in response to that review.

Using the guidelines listed above, the licensee met or exceeded all Technical Specification requirements for operable AC power sources and ECCS during the portion ofRF-3 observed during the inspection period. The licensee intended to utilize the guidelines to the maximum extent possible during the entire refueling outage. The licensee also intended to utilize systems that were available, versus those that fully met the Technical Specification definition of operable, to meet the guidelines. For example, if the system could be put in service quickly either from the control room or out in the plant, without the need to re-assemble components, it was considered available.

Daily outage planning meetings, control room pre-shift briefings, and status meetings held three times a day identified the operable shutdown cooling system(s), AC power sources, ECCS train(s) available, and the alternate decay heat removal methods. Daily reviews of the schedule by the outage planning group and members from the independent outage risk review team assessed potential risk levels associated with work released and scheduled for the following day and week. The outage planning group committed to identify higher risk evolutions, including operations with the potential to drain the reactor vessel, in the refueling plan of the day.

Listed below are examples of licensee practices for maintaining reliable decay heat removal and minimizing the overall shutdown risk during RF-3:

* Contingency plans to close containment in the event of a station blackout were developed. A portable diesel was rented to power the auxiliary hoist needed to close the equipment hatch. Work orders were generated, electrical cables and other equipment were prestaged, and training was conducted prior to the outage.

* Contingency plans were developed to supply temporary AC power to the Division 1 fuel pool cooling and cleanup (FPCC) system from the Division 2 Class 1E busses. This would be implemented in the event of a loss of offsite power with the Division 1 emergency diesel generator out of service and FPCC being used to remove decay heat. Work orders were generated, electrical cables and other equipment were prestaged, and training was conducted. The materials necessary to implement the contingency plans were in place prior to using FPCC for decay heat removal.

* Contingency plans were developed to cross connect the Division 1 and 2 Class 1E busses in the event of a loss of offsite power. This would make two trains of shutdown cooling available with only one emergency diesel generator in operation.

* Decay heat removal capacity curves were incorporated into the plant data book (part of the operating procedures). The curves were to assist the operators in determining if an alternate shutdown cooling system was capable of removing the decay heat.

* During maintenance periods on the startup transformers and the interbus transformers, offsite power was available by a back-feed through the main and auxiliary transformers. Transformer maintenance was to be worked until completion or was to be left in an "all clear" condition such that restoration could be performed in less than 4 hours if an emergency arose.

* During safety relief valve (SRV) replacement, steel blank flanges

were be prestaged to install over SRV openings if the normal work sequence was delayed or if main steam line plug leakage occurred.

A weakness in the RF-3 schedule was identified concerning electrical maintenance on the Unit 2 startup transformer and interbus transformer. Both were scheduled to be out of service near the beginning of the outage. During this maintenance activity decay heat was high, the reactor vessel water level was low, the Division 1 diesel generator was out of service, and both recirculation pumps were secured for chemical decontamination. This maintenance was scheduled prior to the shutdown risk review and could not be rescheduled due to other equipment availability requirements. The licensee identified it as a high risk evolution and closely monitored the performance of the maintenance.

Based on the above review, the inspectors concluded that the licensee developed the RF-3 schedule with adequate defense in depth to minimize shutdown risk. Evidence of a conservative operating philosophy was observed in both the reviews and initial implementation of the schedule. The inspectors will observe the licensee's continued implementation of the schedule and will document their observations in a subsequent report.

11. Items For Which A "Notice of Violation" Will Not Be Issued

During this inspection, certain of the licensee's activities, as described above in Paragraphs 3.c, 3.g, 3.h, 3.1, and 8.b.(2), appeared to be in violation of NRC requirements. However, the licensee identified these violations and they are not being cited because the criteria specified in Section V.G of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C, (1991)), were satisfied.

12. Open Inspection Items

An Inspection Follow-up Item is a matter which has been discussed with the licensee, which will be reviewed further by the inspectors, and which involve some action on the part of the NRC or licensee or both. The open inspection item disclosed during the inspection is discussed in Paragraph 7.g.

13. Exit Interviews

The inspectors met with the licensee representatives denoted in Paragraph 1 throughout the inspection period and on April 13, 1992. The inspectors summarized the scope and results of the inspection and discussed the likely content of the inspection report. The licensee did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

During the inspection report period the inspectors attended the following exit interview:

Inspector	Exit Date
F. Maura	3/31/92